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Evaluating Policies to Increase the Generation of Electricity from Renewable Energy

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Focusing on the U.S. and the E.U., this essay seeks to advance four main propositions. First, the incidence of the short-run costs of programs to subsidize the generation of electricity from renewable sources varies with the organization of the electric power industry, and this variation is may be a significant contributor to their political attractiveness in U.S. states. Second, despite the greater popularity of feed-in-tariff schemes worldwide, renewable portfolio standard (RPS) programs may involve less long-run social risk under plausible conditions. Third, in contrast to the E.U.'s approach to reducing carbon dioxide emissions, its renewables program is almost certain not to minimize the cost of achieving its goals. Fourth, the array of state RPS programs in the U.S. are also almost certain to cost more than necessary, even though most employ market mechanisms. To support this last point I provide a fairly detailed description of actual markets for renewable energy credits (RECs) and their shortcomings.

Introduction

At the start of 2010, eighty-three nations and all U.S. states had policies to promote the generation of electricity from energy deemed "renewable," typically defined to exclude large-scale hydroelectric facilities (REN21 2010, National Research Council 2010 (Appendix D)). As of May 2011, twenty-nine U.S. states[2] and the District of Columbia (referred to a state in what follows for simplicity) have enacted renewable portfolio standard (RPS) policies for this purpose (generally along with other policies). (Unless explicitly noted, all statements in this article about

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[2] These states are Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Illinois, Iowa, Kansas, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Washington, and Wisconsin.

U.S. federal and state policies in support of renewables are based on the online DSIRE database (http://www.dsireusa.org/) and links from it to state and federal online resources.) RPS policies are quantity-based and generally require that a minimum fraction of electricity demand be met by renewable energy. These policies typically require load-serving entities to obtain renewable energy credits (RECs), produced by state-certified renewable generators in proportion to their output, equal to at least a minimum fraction of their retail sales. Bills that would impose a nationwide RPS have twice passed the U.S. House of Representatives since 2007.

Outside the U.S., feed-in Tariff (FIT) policies have been much more popular. FIT policies are price-based and generally require that electricity generated from renewable energy be purchased at a fixed, premium price. FIT policies were employed by fifty nations at the start of 2010, while only ten used RPS. In contrast, FITs have been very little used by U.S. states and have received essentially no recent attention at the federal level (Couture et al 2010). Since 1992 federal support of renewable generation has mainly involved tax credits that provide per-kWh subsidies of generation or fractional subsidies of up-front capital cost (Schmalensee 2010). The adverse incentive effects of subsidizing capital cost are clear; the shortcomings of providing subsidies in the form of tax credits are also serious. This approach generally requires renewable generation developers, who rarely have enough taxable income to make use of tax credits, to partner with one of a few large tax-paying financial institutions who are willing to serve as "tax equity" providers (Bipartisan Policy Center 2011). Forming such partnerships raises costs significantly, with no social benefit.

Focusing on the U.S. and the E.U., this essay seeks to advance four main propositions. First, the short-run incidence of the costs of subsidies to renewable generation depends on the organization of the electric power industry and may be a significant contributor to the political attractiveness of such subsidies. Second, despite the greater popularity of FIT schemes worldwide, RPS programs may involve less long-run social risk under plausible conditions. Third, in contrast to the E.U.'s approach to reducing carbon dioxide (CO_2) emissions, its renewables program is almost certain not to minimize the cost of achieving the program's goals. Fourth, the array of state RPS programs in the U.S. are also almost certain to cost more than necessary, even though most employ "market mechanisms." To support this last point I provide a fairly detailed description of actual markets for renewable energy credits (RECs) and their shortcomings. A final section offers a summary of the main conclusions and implications of this analysis for the design of a possible nationwide U.S. RPS program.

Why Subsidize?

Many economists have argued that subsidizing renewable electricity generation is not an economically attractive approach to achieving most policy goals that have been used to justify such subsidies. (Fischer and Preonas (2010) develop many of the points made in the next several paragraphs.) In this section I briefly summarize the main economic arguments involved and then discuss a potentially important reason why such subsidies seem to be more politically attractive in regions served by competitive wholesale electricity markets.

Energy Security

Subsidizing renewables does nothing for energy security in the U.S., since North America is essentially self-sufficient in coal and natural gas, and only about two percent of U.S. petroleum consumption is used to generate electricity. The issue is more complex in Europe, which depends heavily on imported natural gas. But the output from wind and solar generation is both variable over time and imperfectly predictable, so that generators of both sorts are referred to as variable energy resources or VERs. The greater the fraction of generation coming from VERs as opposed to conventional baseload coal or nuclear plants, the greater the need for gas-fired reserve capacity. Thus subsidizing renewables may not be a sound response to energy security concerns (Moselle 2010). (Accommodating high levels of VER generation also requires significant changes in system planning and operations (NERC 2009).)

Green Growth

Some advocates claim that such subsidies will create "green jobs." But the notion that the aggregate level of unemployment can be affected by this sort of program makes sense only under conditions of substantial unemployment. Even then, however, it seems a priori unlikely that the most efficient way to create jobs in a deep recession would be to subsidize switching from one capital-intensive method of generating electricity to another.

Of course, subsidies for renewable generation will change the composition of domestic employment. Some argue that there will be rapid growth in the global market for renewable generation equipment, and subsidizing domestic demand for renewables will create a strong domestic industry able to compete in that market. At its base this is an argument that the government has found an economically attractive investment opportunity that private capital markets would fail to exploit without a subsidy, an argument not well-supported by history. Moreover, while growth prospects for renewables may indeed be bright, particularly in the long term, the U.S. auto industry demonstrates that a large domestic market does not guarantee a healthy domestic industry (though, to be fair, it surely never hurts). At the end of 2008, for instance, the U.S. led the world in installed wind generation capacity, but half of new installations that year were accounted for by imports.

Climate Change

Perhaps the strongest case for subsidizing renewables in the U.S. is that shifting away from fossil fuels will reduce emissions of CO_2 that contribute to global climate change. No such case can be made in support of the E.U.'s ambitious renewables program (discussed below), however, since aggregate CO_2 emissions there are capped by the E.U.'s Emissions Trading System (ETS) (Ellerman et al 2010). And in the ten U.S. states participating in the Regional Greenhouse Gas Initiative (RGGI), nine of which have RPS programs (VT is the exception), aggregate CO_2 emissions from electricity generation are likewise capped in principle, though the REGGI cap may not be binding in practice. Even where caps do not exist, the key to reducing CO_2 emissions from electricity generation is to reduce the use of coal, but coal-fired power plants generally have low marginal costs, and adding renewable generation to a power system results in a reduction in generation from plants with high marginal costs – typically gas-fired plants.

A related argument is that subsidies that increase output of renewables reduce the costs of renewable technologies via learning-by-doing and thereby encourage their widespread adoption. But learning exists in many industries. It only provides an economic justification for subsidies if there are knowledge spillovers from one producer to others. To my knowledge, such spillovers have not been demonstrated in this context, nor has it been demonstrated that costs are reduced more effectively by subsidizing deployment of today's expensive technologies than by directly supporting research and development or offering prizes tied to generation cost. (Such a prize might be a commitment to purchase a very large quantity of solar electricity at a relatively *low* FIT from the first firm willing to supply at that price.) And in the U.S. context, I don't believe it has ever seriously been argued that any single U.S. state's subsidies for renewables will reduce their costs and enough to have a discernable effect on their global penetration.

Political Support

Even though the strongest arguments for subsidizing renewables probably have to do with climate change, the first nine U.S. RPS policies were adopted before 1999 along with electric utility restructuring, and their political support had nothing to do with climate change or any other environmental issue (Hogan 2008). (Those programs includes California's, which was adopted in 2002 to replace an ineffective renewables subsidy that had been adopted in 1996 in connection with utility restructuring.)

And while climate change and other environmental concerns did play a role in the adoption of the second wave of RPS programs that began in 2004, support for the four most recently adopted U.S. RPS programs seems at best loosely connected to concern about climate change. In June 2009, the U.S. House of Representatives passed the Waxman-Markey bill (H.R. 2454) that would have reduced U.S. CO_2 emissions, despite net opposition from the delegations from Ohio, Missouri, and Kansas. Nonetheless, Ohio and Missouri had adopted RPS programs in 2008, and Kansas, from which three of the four Representatives opposed Waxman-Markey, had followed suit in the month before the Waxman-Markey vote. The 2008 statute establishing the Michigan RPS lists "improved air quality" as the law's fourth purpose, after diversifying energy resources, providing greater energy security by using in-state resources, and promotion of private investment in renewable energy. Climate change is not mentioned.

The fact that RPS policies have been adopted under a variety of different banners is consistent with studies that find that multiple factors influence their political appeal (Chandler 2009, Lyons and Yin 2010). States' renewable resources, which vary enormously, do not seem to be a major factor, however. As noted above, wind power has accounted for most of the growth in U.S. renewable generation in recent decades (Schmalensee 2010) The National Renewable Energy Laboratory (U.S. Department of Energy, no date) estimates that seventeen states have annual potential wind generation more than four times their 2009 retail sales (from EIA). Ten of these states have RPSs. Eighteen states (including the District of Columbia) have estimated wind potential of less than ten percent of 2009 retail sales; nine of these have RPSs.

To my knowledge the governance of electricity supply has not been formally considered a determinant of the decision to subsidize renewables, but theory and a bit of evidence suggest that it may be an important factor. In states with rate-of-return regulation, utilities are entitled to earn a fair rate of return on their sunk investment in fossil-fueled generating plants, even if those plants are run less to make room for renewable generation. Thus ratepayers must bear all the incremental costs of shifting to renewables that are not borne by taxpayers. In contrast, in the twenty-nine states where all or most electricity is traded in organized wholesale markets managed by Independent System Operators (ISOs) or Regional Transmission Authorities (RTOs) and in the E.U., the returns earned by independent power producers (IPPs, generators that do not serve retail customers) are *not* guaranteed. These profits (or, more properly, quasi-rents) can be expected to fall in the short run as excess capacity reduces IPPs' output and drives down wholesale electricity prices. Thus some of the short-run costs of RPS programs are shifted from ratepayers to generators.

Such a shift seems to have been important under an FIT program in Germany (Frondel et al 2010), and the drop in generators' returns because of Spain's FIT program may have been sufficient actually to lower retail rates (Sáenz de Miera et al 2008). Appendix A illustrates how the addition of high-cost renewables under an RPS program can cause a short-run rate decline when fossil supply is inelastic. In the long run, of course, ratepayers necessarily bear all the costs of RPS or FIT programs, but the long run does not arrive rapidly in electric power.

In the U.S., the 2011 reference case projection of the U.S. Energy Information Agency (EIA) implies that under current policy, between 2008 and 2015 U.S. electricity generation will increase only 3.1 percent. Fossil-fuelled capacity is projected to rise by 2.1 percent, while renewable capacity is expected to increase by 23.5 percent and renewable generation to increase by 44.4 percent. (The EIA projects a dramatic slowdown in renewable capacity growth after 2015 because the main federal subsidy programs expire in that year, and projecting under "current policy" requires the EIA to assume that these popular programs won't be extended.) Not surprisingly, U.S. generation from fossil-fueled plants is projected to *decline* by 2.3 percent, with greater declines plainly expected in states with RPS programs. Whether these declines will be sufficient to lower wholesale prices is unclear, but IPP quasi-rents will surely be reduced.

Whether the ability to shift some short-run costs of an RPS from ratepayers to IPPs makes it more or less likely that a state will adopt an RPS, all else equal, depends on IPPs' political effectiveness. Since they lack retail customers and have relatively few employees, one might expect them to be less politically effective than, say, comparably-sized distribution companies. At any rate, that's what the evidence suggests. Of the sixteen states with organized wholesale markets in which IPPs accounted for more than thirty percent of generation in August, 2010 (according to EIA's *Electric Power Monthly*), fifteen have RPS programs. (The exception is Vermont, an active supplier of renewable generation and RECs in the New England market.) At the other extreme, of the eleven states not in ISO/RTO regions in which IPPs account for less than twenty percent of generation, only three have RPS programs. (The exceptions are New Mexico, North Carolina, and Washington.)

Particularly in multi-state organized markets, the in-state importance of IPPs is an imperfect measure of the ability to shift costs to IPPs, of course, and decisions regarding RPS programs, ISO/RTO status, and the role of IPPs are all endogenous to the political system. This evidence can accordingly only be suggestive of a causal relation.

RPS or FIT?

Most analysts seem to believe that price-based FIT policies are superior to quantity-based RPS approaches. The European Commission (2008, p. 3; italics in original) has neatly summarized the general view: "*well-adapted* feed in tariff regimes are generally the most efficient and effective support schemes for promoting renewable energy."

This conclusion rests in part on experience in the E.U., where FIT regimes in, e.g., Spain and Germany, outperformed the RPS regime in the U.K., though siting problems in the U.K. and the success of the RPS policy in Texas suggest that the relation between these policies in practice is more complex. The clearest theoretical argument for FIT's superiority is that guaranteeing the price removes electricity market risk from investors in renewable generation, so that more capital can be raised per dollar of subsidy expense. But this "bang for the buck" measure neglects impacts on other actors besides investors in renewables and those who pay subsidies. Devices for that remove market risk from one set of players may simply shift it to others and not reduce risk to society as a whole. There is accordingly no obvious reason why overall social risk cannot be higher under an RPS than an FIT, but overall social risk seems to have received little analytical attention.

Appendix B presents a simple model that illustrates that total social risk, as measured by the variance of the total cost to society of meeting the (inelastic) demand for electricity, may be higher under a FIT than under a comparable RPS, even though individual investors bear no risk under an RPS. In a very stylized, long-run model of a large electric power system with fixed total load, I compare an RPS and an FIT that would have the same cost and deliver the same generation mix under certainty. Fossil generation at the system level is assumed to operate under constant returns to scale with known costs, while the supply curve of renewable energy is assumed to be rising (because potential sites vary in quality), and the quantity supplied at any price is assumed to be ex ante uncertain. The model shows that as long as the unit cost of renewables is always higher than the unit cost of fossil electricity, the variance of the total cost of serving the fixed load, a natural measure of total social risk, is always higher under FIT than RPS. The difference is greater the more elastic is the renewables supply curve, since what drives the result is uncertainty regarding the quality supplied (and subsidized) under an FIT policy.

There are, of course, obvious design features that can reduce the riskiness of both types of policy. FIT regimes could have a fixed maximum quantity eligible for the subsidy, for instance, and RPS regimes could have a cap on total costs. It is interesting that FIT regimes in the E.U. have generally not had quantity limits (Couture et al 2010), and some have experienced significant positive quantity surprises, while nine of the 30 U.S. RPS programs have explicit cost caps. These caps limit RPS-induced retail rate increases to between one and four percent. (One of the nine cost-cap states, Montana also sets the penalty for non-compliance at $10 per MWh, effectively ruling out purchase of expensive renewable power.)

I hasten to add that I doubt that considerations of social risk explain why, despite experience in the E.U. and the weight of expert opinion, U.S. states have overwhelmingly chosen RPS over FIT to subsidize renewable generation. States may have bad memories of their experience under the Public Utilities Regulatory Policies Act (PURPA) of 1978, which required them to purchase renewable generation at utilities "avoided cost," thereby establishing an FIT-like regime. Or they may have been reluctant to attempt to set wholesale rates for renewable power, given FERC's jurisdiction over wholesale power rates. But the FERC first opined on a (very limited) state FIT in October, 2010 (133 FERC ¶ 61,059 2010). And neither of these considerations explains the complete lack of interest in FIT approaches at the federal level.

It is thus something of a puzzle why U.S. politicians so strongly prefer RPS to FIT. Perhaps quantity goals are generally more attractive than price goals, as the universal use of the former rather than the latter in international climate change negotiations might suggest. Or perhaps, more cynically, it may be easier to get RPS programs adopted where environmental groups are only moderately strong because the costs of RPS programs are less visible than the costs of FIT programs. It is not hard to find Americans who think wind and solar power must be cheap because their "fuel" is free; I expect it is more difficult to find Spaniards or Germans who share this mistaken belief.

Is the E.U. Renewables Program Ex-Post Efficient?

The notion of ex-post efficiency, explored in this section and the next, involves taking detailed policy goals as given and asking whether they are likely to be attained at minimum cost or anything close to it. In the case of renewable energy this mainly requires production at the best sites, given the technologies required or allowed to be employed.

The goals of the E.U.'s renewable energy program are simply stated: twenty percent of overall energy and ten percent of energy used in transportation must come from renewable sources by 2020 (European Union 2009). The relevant directive defines "renewable" fairly broadly and argues, plausibly, that because transportation fuels are freely traded, there is no reason why the same ten percent requirement should not apply to all member states.

Ex post efficiency as regards the top-line twenty percent target requires E.U.-wide equalization of the marginal cost of producing electricity from renewable energy. Assuming no within-country inefficiencies, this goal could be attained in at least three ways. First, a uniform E.U.-wide subsidy or FIT regime could be employed – and, to hit the overall renewable-share target, adjusted as information about quantities supplied emerged. Second, almost any set of national goals could be specified, as long as a system of RECs tradable E.U.-wide was in place. Finally, of course, even without international trading, a set of national goals could lead to ex-post efficiency if they were carefully set so as to equalize marginal cost of compliance across countries. Of course, even if a set of national renewable-share targets is met exactly, unless those targets are identical, different patterns of national growth rates will lead to different shares of renewables for the E.U. as a whole.

A Union-wide subsidy scheme seems not to have received serious attention, perhaps because member states were attached to their existing array of FIT regimes, but there was a good deal of debate within the E.U. about establishment of a Union-wide REC system (Toke 2008). In the end, however, in part because of protests from Germany and Spain, along with their renewable energy industries, the final directive allowed for only limited government-to-government trading as well as joint projects.

As noted above, limits on international trading would not lead to appreciable ex-post inefficiency if national targets were carefully chosen to ensure that marginal costs of compliance were roughly equal. But the E.U.'s statement of its target-setting procedure suggests at least as much concern with equity as with efficiency:

> It is appropriate [to share] the required total increase in the use of energy from renewable sources between Member States on the basis of an equal increase in each Member State's share weighted by their GDP, modulated to reflect their starting points, and by … [taking account of] Member States' past efforts with regard to the use of energy from renewable sources. (European Union 2009, ¶15)

To get some sense of the relative importance of national wealth in the target-setting process relative to other factors, I performed the following simple exercise. The Directive (in Annex 1) gives for each Member State the 2005 share of its energy from renewables (C) and its 2020 target (T). For each State (excluding Cyprus, Luxembourg, and Malta for various reasons) I computed two measures of the toughness of its target: an absolute measure, (T-C), and a relative measure, (T-C)/C. Four nations were in the top third of Member States according to both measures – Germany, United Kingdom, Netherlands, and Ireland – and four nations were in the bottom third according to both measures – Romania, Latvia, Lithuania, and Estonia. The 2005 per-capita GDP of the poorest country in the top group was more than 3.3 times that of the richest country in the bottom group. Clearly ability to pay had an important role, perhaps the dominant role, in the determination of national targets.

Not surprisingly, two independent studies have concluded that the cost of restricting international trading, given the national targets chosen, is substantial: about €17 billion annually in 2020, roughly twenty percent of the cost with unlimited trading (Eurelectric 2009). The contrast with the E.U.'s pioneering ETS for capping Union-wide carbon dioxide emissions efficiently could hardly be stronger (Ellerman et al 2010).

Are the U.S. State RPS Programs Ex-Post Efficient?

Since states make independent political decisions regarding RPS programs, and, as I noted above, the presence of RPS programs seems unrelated to the availability of renewable resources, it is extremely unlikely that state RPS targets equalize the marginal cost of renewable generation. Total national costs of the meeting states' aggregate targets could nonetheless be minimized, at least with respect to the twenty-seven REC-using states, if all RECs were nationally traded in efficient, competitive markets. (The three states that do not use RECs are New York (which uses a system of centralized procurement), Iowa (which requires ownership of or contracts with specific facilities), and Hawaii (where the statue simply makes no mention of RECs).) Unfortunately, as I show in the rest of this section, there there are enormous obstacles to both interstate trade and market efficiency.

No two of the thirty U.S, RPS programs are identical, and the differences are often substantial. Some programs appear highly ambitious, others much less so. Iowa, for instance, simply requires its utilities to own or contract with 105 MW of renewable generation capacity, even though there are currently 3,675 MW of wind generation capacity in the state (AWEA n.d.). Most states specify an alternative compliance payment (ACP) for each MWh by which load-serving entities fall short of meeting their requirements, but ten appear to leave enforcement to the discretion of their public utility commissions. Most ACPs are around $50/MWh, but some are as low as $10, and those relating to solar-specific requirements are much higher, with the New Jersey solar ACP highest at $675/MWh. Normally if there are not enough RECs available to meet utilities' requirements in a given year, one would expect the corresponding REC price to approximate the ACP. If such a shortage ever develops in RECs eligible to satisfy the Missouri RPS it will be interesting to see what happens, since the Missouri ACP is specified by statute as twice the REC price.

No two states use the same definition of "renewable," and twenty operate under laws that set multiple tiers or classes of technology-specific requirements. Renewable energy sources like geothermal or municipal biomass produce predictable generation, while at substantial penetration variable energy resources (VERs) sources like wind and solar require additional reserve capacity and changes in system operations and, in some cases, are sited remotely and require large investments in transmission capacity (NERC 2009; National Research Council 2010, ch. 6). No state RPS program systematically dis-favors VERs, however. In fact, twelve programs have specific requirements for the use of solar energy, and, as noted above, wind has accounted for the bulk of increases in renewable generation in recent years. If use of all technologies designated "renewable" are thought to produce equal benefits, it follows that it would reduce total social costs if policy favored technologies that imposed fewer external costs on the balance of electric power systems.

Some features of RPS programs are clearly aimed at promoting in-state economic activity. Texas and other states give credit only for renewable generation that serves in-state customers, for instance, and New Jersey has requirements for in-state solar generation and, effective in 2011, for in-state off-shore wind. North Carolina has minimum requirements for electricity generated using swine waste and using poultry waste.

In-state solar requirements, particularly when coupled with requirements for distributed generation, seem aimed at generating jobs installing and maintaining solar cells rather than manufacturing them. According to the EIA, in 2008 Ohio and Michigan accounted for sixty-one percent of solar cells manufactured in the U.S., and California and Massachusetts accounted for another twenty percent. Of these four, only Ohio and Massachusetts had solar RPS requirements. No solar cells at all were produced in five states with solar requirements, and there was some production in six states without solar requirements.

Other requirements are somewhat harder to understand. For instance, both the District of Columbia and New Hampshire allow RECs from renewable generators over a fairly wide geographic area to be used for compliance. Nonetheless the District of Columbia has three technology-specific requirements within its overall RPS, and New Hampshire has four. These can have very little to do with in-state generation, particularly in the District of Columbia. At most these technology-specific requirements could have some minor impact on the region-wide renewable generation mix. It seems implausible that they could have been expected to have a measurable effect on aggregate learning-by-doing in any market area.

Interstate Trade in RECs

To assess whether the states' goals for renewable generation, whatever their merits, are met reasonably efficiently, it is necessary to understand the mechanics of RPS programs. In the twenty-seven REC-using states, each state must certify that RECs produced along with electricity by particular generating facilities can be used for compliance with one or more state-specific requirements. The generation, transfer, and retirement of RECs are generally tracked in online registries (http://www.etnna.org/learn.html). All information in these registries is treated as proprietary and is only available to market participants. This is in stark contrast to the emissions trading systems administered by the U.S. Environmental Protection Agency, in which all such information is public (http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.progressresults_allowance). RECs are often bundled with electricity in long-term arrangements between generators and distribution companies; a number of brokers facilitate over-the-counter trades of "unbundled" RECs; and aggregators assemble RECs from multiple sources to meet utilities' requirements. (A list of brokers and other participants in these markets is maintained by the U.S. Department of Energy: http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=2.) Most (but not all) states use a calendar-year compliance period, allowing a few months after the end of the year for load-serving entities to acquire and turn over the necessary number of RECs.

Colorado and Missouri allow RECs purchased from certified generators anywhere in the US to be used for compliance purposes, but both give twenty-five percent additional credit for in-state generation. Of the remaining twenty-five REC-using programs, fifteen will accept REC from facilities that do not deliver power in-state, but eligible facilities typically must be located in the same ISO or RTO or in the same geographic region. Washington only accepts RECs from the Pacific Northwest, for instance, and Deleware accepts RECs only from the PJM RTO.

On the other hand, distribution companies in at least some of the fifteen states that allow inter-state trading and generators there and elsewhere do engage in substantial interstate (and even international) trade in RECs. Because information in the various REC registries is treated as proprietary, no systematic data on interstate transfers of RECs are available. However, Table 1 shows that the few state compliance reports that do provide such data show substantial imports.

In Table 1, it is worth noting that Vermont, Virginia, and West Virginia do not have RPS programs, and Michigan's wasn't enacted until 2008.

Table 1.

RPS Compliance Using Out-of-State Generation

State	REC, Year	Percentage Out of State	Main Sources
Connecticut	Class I, 2007	97.5	Maine, New Hampshire, Rhode Island, New York
Connecticut	Class II, 2007	43.6	Massachusetts, Maine, Vermont
Maryland	Tiers I & II, CY2007	83.7	Pennsylvania, Virginia, Michigan
Massachusetts	2008	90.0	New York, Maine, New Hampshire, Quebec
New Jersey	Class I, RY2009	85.4	Illinois, Pennsylvania, West Virginia, Virginia
New Jersey	Class II, RY2009	54.4	Pennsylvania, Maryland
Rhode Island	New, 2008	91.9	New Hampshire, New York, Vermont
Rhode Island	Existing, 2008	100.0	Massachusetts, Vermont, New Hampshire

Notes : Data from most recent state compliance reports available online in mid-November, 2010. "CY" and "RY" refer to compliance year and reporting year, respectively. Massachusetts had only one RPS requirement in 2008; in 2009 it was renamed Class I and a Class II requirement was added. Definitions of technologies covered by the RECs shown may be found in http://www.dsireusa.org.

REC Market Fragmentation and Transactions Costs

It is possible to get some information on REC prices, though only in the over-the-counter market. I have purchased end-of-month bid-ask data from May, 2006 through August, 2010 from Spectron, a leading broker. Figures 1-3 below also rely on bid-offer data for earlier months that had been made public by Evolution Markets, another leading broker. In May, 2006, Spectron provided quotes on RECs from only five states (Connecticut, Maryland, Massachusetts, New Jersey, and Texas), and Evolution Markets covered only one additional state (Maine). Over time, as I discuss just below, coverage has expanded as RPS programs have spread.

Looking at the raw price data, one is first struck by the wide range of REC prices. On August 31, 2010, for instance, all bids for solar RECs for New Jersey, Pennsylvania, Maryland, Delaware, and Ohio were at least $300/MWh, while other, non-solar bids and offers ranged from $.05 to $35.00. This extreme price dispersion is inconsistent with ex post efficiency in meeting states' goals for renewable generation and, as I show next, it reflects results in markets that are fragmented and thin, with high transactions costs. Moreover, I then show that price movements in a few relatively thick REC markets for which information on supply and demand conditions is available publicly with a lag strongly suggest that traders in these markets do not have good private information.

Of the twenty-seven REC-using state RPS programs, seven have requirements that begin in 2010 or a later year. As of June, 2010, Spectron provided quotes for RECs in only half of the remaining twenty states. Three more were added by August. Presumably there was insufficient trading volume in the other states' RECs to make it worthwhile even to post bid-ask quotes with wide spreads. Because most states' RPS programs have multiple requirements, at the end of August, 2010, Spectron provided quotes for thirty-three different RECs from the thirteen states it covered.

These markets are further fragmented because RECs can be banked only for a limited time except in Arizona and Oregon. (Neither Evolution Markets nor Spectron provided quotes for RECs from either state during any month in my sample.) Colorado allows banking for five years, and Ohio and Wisconsin allow banking for four years. Most of the other REC-using programs allow banking for only two or three years. Limiting banking reduces the incentive for early investment in large-scale generation, of course, and it also makes RECs produced in different years imperfect substitutes and thus further fragment markets. In August, 2010, Spectron provided bid-offer quotes for an average of two different vintages per REC, for a total of sixty-six different markets. (Over the whole May, 2006 to August, 2010 period the average of vintages quoted per REC was essentially the same.)

Fragmented, thin markets lead to high transactions costs, as market-makers need to quote high bid-ask spreads to cover illiquidity risks. Over all the Spectron data, the average bid-ask spread for the current-year vintage was thirty-eight percent. By way of comparison, spreads for municipal and corporate bonds in 1995-97, when both were also traded in fragmented, broker-mediated, over the counter markets, averaged 0.23 percent and 0.21 percent, respectively (Chakravarty and Sarkar 2003). Spreads of one hundred percent or more are not uncommon in the Spectron REC data: there were ten in the sixty-six quotes posted on August 31, 2010, for instance.

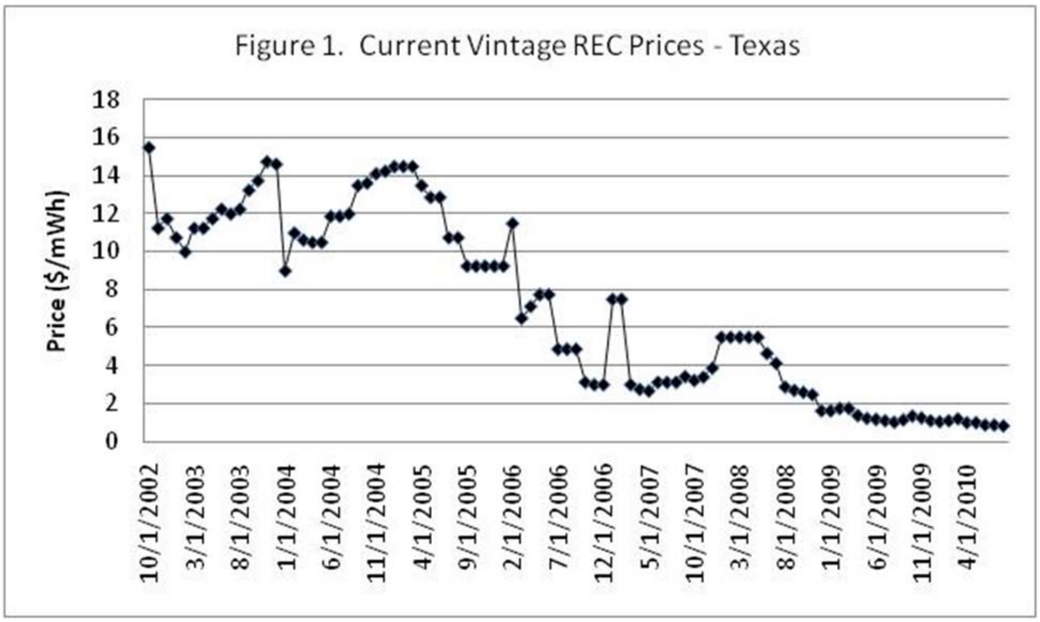
Information and Market Efficiency

If participants in REC markets had good, current information and if there were no banking, one would expect to see a bimodal distribution of current vintage spot market prices, particularly toward the end of each compliance period, as uncertainties about renewable generation and REC requirements were resolved. If the market were expected to be *long* at the end of the compliance period, with more than enough RECs produced to meet RPS requirements, the price should tend to zero. (This is basically what happened in the E.U. ETS at the end of the first compliance period (Ellerman et al 2010).) On the other hand, if the market were expected to be *short*, with fewer RECs produced than required, one would expect REC prices to tend to near the ACP level. If some banking is allowed, prices should tend to some positive number, well below the ACP, if the market is expected to be long, particularly if it is expected to stay that way for a year or more, but prices should still be near the ACP level if the market is short.

If no interstate trading is allowed, it should be relatively simple for market participants, including brokers, to learn whether the market was likely to be long or short at the end of each compliance period, particularly if the relevant authorities regularly and promptly published information on market conditions. New Jersey's solar requirement, for instance, can only be met by in-state generation; New Jersey publishes detailed reports on ACP payments, market conditions, and their determinants; and these reports appear promptly, at least compared to the reports of other states. (A draft of the report for Reporting Year 2009, which ended on May 31, 2009, was produced in February, 2010.) These reports show a market that has been consistently and substantially short and, not surprisingly, New Jersey solar RECs (called SRECs) consistently trade just below the ACP level in a fairly liquid market: spreads in the Spectron data averaged 6.1 percent. These prices appear to have tracked the fundamentals in this market well.

On the other hand, of the eight REC-using states with compliance requirements beginning in 2009 and earlier that only count RECs from facilities that deliver power in-state, seven do not seem to publish *any* information about REC market conditions. Only Texas (via its grid operator, the Electric Reliability Council of Texas (ERCOT)) has such information readily available on line. The Texas reports are detailed and prompt relative to other states: the Texas report for calendar 2009 was available online by mid-November, 2010. These reports show a market that has been long by a substantial margin since its inception, with planned wind capacity increases likely to prolong this state of affairs.

Figure 1 shows current-vintage REC market prices that are not easily reconciled with these fundamentals: REC prices remained substantial (though low relative to the $50 ACP level) until 2006. (This Figure and those below show arithmetic means of bid and ask prices.) It has been suggested that market participants were building REC banks through 2006 to deal with uncertainty, particularly about the future of the federal production tax credit. (In the 1999-2004 period, the production tax credit lapsed three times (National Research Council 2010, p. 148).) While this is described by participants as an active market, current-vintage bid-ask spreads in the Spectron data averaged 37%.



Source: See text. Qualifying renewable energy facilities must have been installed after September 1999; eligible energy sources include solar, wind, geothermal, hydroelectric, wave or tidal energy, biomass, or biomass-based waste products, including landfill gas.

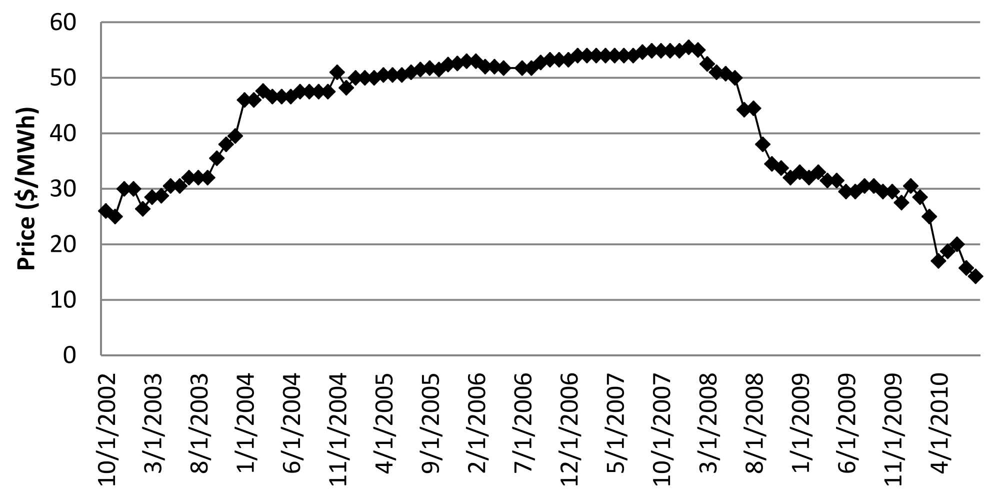
Things are more complicated in principle when interstate trading is allowed. RECs produced by a wind farm in Vermont, say, can be used to satisfy RPS requirements in any other New England state. A good deal of information on renewable generation in several states and Canadian provinces, along with information on RPS requirements and REC banks throughout

New England would be required for a generation facility or distribution company in, say, Rhode Island to have a well-informed view of the likely future REC prices it would face.

It is possible that the necessary information can be acquired by sophisticated traders from REC registries and other sources, but the states involved do not do much to help. Of the twelve states that allowed RECs produced by facilities that did not deliver power in-state to be used for compliance and that required compliance beginning in 2009 or earlier, four do not seem to post comprehensive RPS program reports. The reports of the other eight vary considerably in promptness: as of mid-November, 2010, only three states had posted reports dealing with all or part of 2009, while the most recent reports from three other states covered 2007. These reports also provide very different amounts of information. Several provide only ACP data, and only a few provide enough information from which one could assess market conditions.

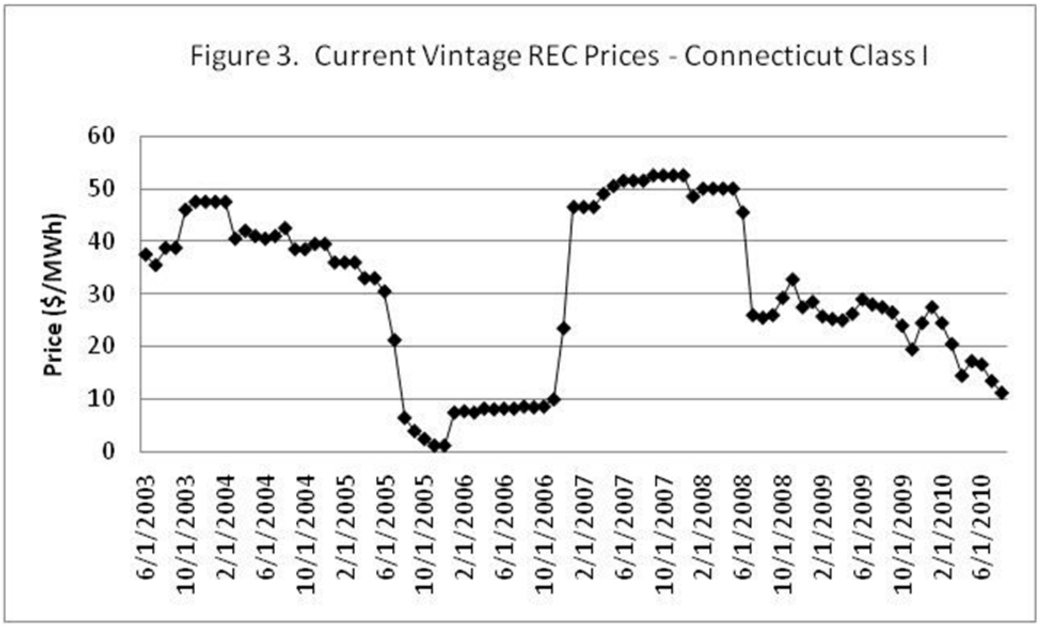
Markets for Massachusetts and Connecticut RECs have been among the more active, and their state reports were among the more informative (though Connecticut's have not been particularly prompt), so one can compare current-vintage REC prices with market fundamentals. Figure 2 shows these prices for Massachusetts Class I RECs. Spreads in this market averaged 8.2 percent in the Spectron data and were generally lower before 2008. This market was short in the 2003-06 period, with twenty-six percent of compliance in 2006 taking the form of ACP payments. In 2007, however, the market was long: banking amounted to five percent of requirements. The market remained long in subsequent years. It seems clear from Figure 2 that it took market participants essentially all of 2007 to realize that the market was no longer short.

Figure 2. Current Vintage REC Prices - Massachusetts Class I



Source: See text. Qualifying renewable energy facilities must have been installed after 1997; eligible energy sources include solar, wind, geothermal, ocean (thermal, wave, or tidal), fuel cells using renewable fuels, landfill gas, certain hydroelectric facilities, and low-emission advanced biomass conversion technologies.

Figure 3 shows prices for Connecticut Class I RECs, for which bid-ask spreads averaged 11.7 percent in the Spectron data. This market was long in 2004 and 2005, twelve percent short in 2006 (the ACP was $55), and 0.2 percent short in 2007. Prices seem to have been inexplicably high until mid-2005, then so low during 2006 that participants must have been unaware of the impending shortage. After significant ACP payments were required for 2006, prices finally jumped in early 2007 to levels reflecting a short market.



Source: see text. Eligible energy sources (regardless of when facilities were built) include solar, wind, fuel cells (any fuel), landfill gas, ocean (thermal, wave, or tidal), certain hydroelectric facilities, low emission advanced renewable facilities, and sustainable biomass facilities.

Summary & Implications

This essay has examined a number of aspects of policies to subsidize the generation of electricity from renewable energy. Analysts generally agree that such policies are not an efficient way to reduce CO_2 emissions. Their appeal derives from other sources, one of which, I argued above, is the ability in competitive electricity markets to impose some or all of the attendant costs on generators rather than ratepayers, at least in the short run. The incidence of RPS policies in the U.S. is at least consistent with this argument.

Globally, the FIT approach is more popular than the RPS approach, importantly, it seems because the FIT approach removes risk from investors in renewable generation. But removing risk from investors may serve mainly to shift it to other actors and not to reduce risk to society as a whole. I presented a simple model showing that the long-run risk to society as a whole may in fact generally be lower under the RPS approach, at least unless steps are taken to limit the range of possible renewable generation levels under an FIT regime. This possibility has surely not helped make the RPS approach much more popular than the FIT approach in the U.S., but it is not apparent what has done so.

Because CO_2 emissions in the E.U. are capped by the E.U. ETS, the E.U.'s policy to increase its use of renewable energy can have no effect on those emissions. Moreover, national targets under the E.U. renewables policy are systematically more challenging for wealthier countries, so that the policy's limits on international REC trading seems highly likely to inflate its costs – as others' detailed analysis has confirmed.

Finally, in the U.S. some state RPS goals seem mainly to be about local job creation, while the environmental or other rationales for some other states goals are not simply obvious. Because most states have multiple technology- or location-specific goals and all but two states limit banking, REC markets are fragmented and thin, and transactions costs are quite high. Most states limit interstate trading and provide little information from which one could infer REC market conditions, and even in relatively active markets REC prices are sometimes markedly out of line with their fundamental determinants.

As noted at the beginning of this essay, bills that would impose a nationwide RPS have twice passed the U.S. House of Representatives since 2007. The findings in the preceding section, along with the experience with the U.S. acid rain program (Ellerman et al 2000) and the E.U. ETS (Ellerman et al 2010) have clear implications for the design of any federal program that would impose quantitative requirements for clean and/or renewable electricity generation. First any such program should pre-empt state RPS regimes and should allow unlimited nationwide REC trading. A state standard tighter than the federal standard would likely have no effect on the national generation mix and would in any case raise in-state and national costs (Goulder and Stavins 2011).   Second, to avoid market fragmentation, there should be only one class of REC. Technology-specific multipliers could be used to penalize some VER technologies for the costs they impose on the electric power system or, perhaps, to reward some technologies because of the perceived external effect of induced learning-by-doing if their production is increased. Finally, unlimited banking should be allowed both to reward early large-scale investment and to avoid fragmenting REC markets by vintage, and information on market condition (including levels of REC banks) should be compiled and provided quickly to market participants. And, of course, as in other U.S. emissions trading programs, information on quantities of RECs held and traded should be publicly available.

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Appendix A

To see how electric rates could fall even though ratepayers pay a premium for incremental renewable generation, consider a simple system with fixed load Q. Let R be the quantity of renewable generation added to the system, let r be its per-unit average cost, net of any tax-financed subsidy, let s(Q-R) be the short-run supply curve of fossil generation, and let T be total payments by ratepayers for electricity. If the marginal cost of renewable generation is zero, T must equal the cost of renewables, rR, plus the payments to fossil generators necessary to induce them to supply (Q-R), so

$$T = rR + (Q-R)s(Q-R).$$

Now consider a mandate that increases R slightly. Because Q-R must fall and the fossil supply curve is upward sloping, the wholesale market price must fall and thus the quasi-rents of fossil generators are cut. Moreover, it is immediate that

$$dT/dR = (r - s) - s/\mu,$$

where μ is the fossil elasticity of supply and s is the wholesale price of electricity, equal to the marginal cost of fossil generation. The less elastic is fossil supply, all else equal, the more likely it is that increasing R lowers T, so that that fossil generators bear more than the full cost of increasing renewables in the short run. See Fischer (2009) for a much more complete discussion.

Appendix B

In a large electric power system, it seems reasonable to assume that the long-run unit cost of fossil-generated power, c_f, is roughly independent of system scale, but it is likely to be higher the greater the penetration of renewable VERs:

$$c_f = \gamma + \delta\left(Q_r / Q_f\right),$$

where Q_r and Q_f are the quantities of renewable and fossil generation, respectively, and γ and δ are positive constants. The supply curve of renewable generation is assumed to rise because sites vary in quality and to be uncertain *ex ante*:

$$p_r = \alpha + \beta Q_r + \varepsilon,$$

where α and β are positive constants, and ε is a random variable with mean zero. Total load, Q is assumed fixed for simplicity; the argument below goes through if it also has an additive stochastic component.

We want to compare an FIT of T with an RPS of R that is equivalent under certainty (i.e., when $\varepsilon = 0$), so we assume $T = \alpha + \beta R$. Under certainty, the total social cost of electricity under either policy is

$$\overline{C} = p_r Q_r + c_f (Q - Q_r) = \left(T + \delta\right) R + \gamma\left(Q - R\right).$$

When uncertainty is present, p_r is stochastic under the RPS, and total social cost is simply

$$C_{RPS} = \overline{C} + R\varepsilon.$$

Under the FIT, Q_r is stochastic when uncertainty is present, and a bit of algebra yields

$$C_{FIT} = \overline{C} - \left(R + \frac{\left(\alpha + \delta\right) - \gamma}{\beta} \right)\varepsilon.$$

Note that positive values of ε (positive cost shocks to renewables) raise the cost of an RPS but, by reducing quantity supplied, lower the cost of an FIT. The key point here is that as long as $\alpha + \delta > \gamma$, so that the full incremental cost of renewable electricity always exceeds the incremental cost of fossil electricity, the variance of total social cost is higher under FIT than under RPS. All else equal the difference is larger the smaller is β, that is, the flatter is the renewable supply curve and thus the more responsive the quantity of renewables is to cost shocks when price is fixed, as it is under an FIT.